

## EOE PERFORMANCE PREDICTION MODELS

### FY85 Status Report Project BE2B

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## FY 85 Status Report Project BE2B

By William Henline<sup>1</sup>, Mark Young,<sup>2</sup>, and John T. Nguyen<sup>3</sup>

### FOREWORD

This status report represents the year-end deliverable for Project BE2B for FY85. As such, it will describe the current state of work resulting from efforts in FY85, since the last significant reporting document was released. That report (NIPER-54, March 7, 1985) "Feasibility Study to Modify the DOE Steamflood and CO<sub>2</sub> (Miscible) Flood Predictive Models Respectively to Include Light Oil Steamflooding and Immiscible Gas Drive," indicated the need and feasibility to modify the aforementioned models and outlined the technical and programmatic steps necessary to achieve the modifications. This status report reflects the activities, directional changes and results of the work during the period since the feasibility report.

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## I. Status of Modifications to the DOE Steamflood Predictive Model (SFPM) to Include Light Oil Steamflooding

As outlined in the BE2B feasibility study (NIPER-54), to successfully model the behavior of "light oil" containing reservoirs undergoing steamflooding, the simulator must account for the associated vapor/liquid equilibrium effects. Since light crude oils (and some heavy crudes) contain a significant fraction of low boiling hydrocarbon components, the elevated temperatures produced by steaming will cause selective vaporization (distillation) of these compounds to the vapor (steam) phase. To account for this in a process simulator, the methodology for determining this phase equilibration and its effect on phase fractional flows must be included. These inclusions can be made most appropriately under the following assumptions.

### Thermodynamic Assumptions

1. Ideal oil solutions
2. Oil insoluble in liquid water phase
3. Vapor-liquid equilibrium distributions obtained from fugacities determined from an appropriate equation of state.

### Transport (fractional flow) Assumptions and Modification

1. The steam zone now has significant partial pressure of hydrocarbon components, requiring modification of the fractional flow governing equations.
2. Fractional flow treatment will be modified by assuming local thermodynamic equilibrium exists between the steam and hot liquid banks. Thus, one can write:

$$f_{s,s^0s,s} = \sum_i f_{i,s^0i,s} \quad (I.1)$$

i = species i

Subscript (s) refers to steam zone or steam vapor

$f_{i,j}$  = fractional flow of species i in zone j.

$\rho_{i,j}$  = mass density of species i in zone j.

also

$$f_{i,s} = f(S_{i,s}, S_{j,s}; \dots) \quad (I.2)$$

where

$S_{i,s}$  are saturations of species i in the steam zone.

### Hydrocarbon Steam Zone Saturation Calculations

Phase species distributions are determined from species K-values, i.e.,

$$K_i^{(s)} = \frac{S_{i,s}}{S_{i,L}} = K_p \frac{Y_{i,s}}{X_{i,L}}, \quad (I.3)$$

where

$K_p$  = a function of saturation

X & Y are mole fractions.

Now,

$$\frac{Y_{i,s}}{X_{i,L}} = \frac{\phi_i^L}{\phi_i^s} \quad (I.4)$$

where  $\phi_i^j$  are fugacity coefficients determined from the Peng-Robinson equation of state.

Thus

$$\ln \phi_j = (RT)^{-1} \int_0^P \left[ \left( \frac{\partial V}{\partial n_j} \right)_{T,p,m_j} - \frac{RT}{p'} \right] dp' \quad (I.5)$$

and

$$P = \frac{RT}{V-b} - \frac{a(T)}{V(V+b) + b(V-b)} . \quad (I.6)$$

The implementation of these changes has been underway since April, 1985, and in a general sense they have been added to the SFPM code. Specifically, the subroutine INTCMP, which performs steam zone growth calculations based on fractional flow and energy balance solutions for the respective steam zone saturations SW(4), SG(4) and SO(4) i.e. liquid water, vapor (steam) and liquid oil has been modified to redetermine the proper ratio (liquid/vapor) SO(4)/SG(4) based on a multi-component oil/steam flash calculation. In general, the fractional flow equations in INTCMP ultimately must include individual terms for the fractional flow of each individual oil species as shown in equation (I.1). In practice the viscosity and density differences among individual oil species in the vapor and liquid are small enough to presently ignore their effect on total phase fractional flow. As of now, for code testing purposes, the compositional effect of oil species on vapor/liquid physical and thermodynamic properties as well as relative permeabilities is being neglected. The effect of this assumption will be examined later.

Multi-component vapor/liquid equilibrium flash calculations are now performed using the Peng-Robinson equation of state based Newton-Raphson solution procedure. This computer program performs an isothermal flash in oil/water systems at reservoir conditions. As installed in the INTCMP subroutine portion of SFPM, the flash calculation determines the equilibrium distribution of steam (water) and oil species between the vapor phase (steam plus oil) and the liquid oil phase. The bulk liquid water phase is excluded from the flash calculation. Currently, flash calculations have been run over ranges of temperature and pressure typical of steamfloods (400°-600° F and 150 to 600 psig) for a steam/six (6) component oil system (23° API). The Peng-Robinson equation of state model for this system, as of now, assumes no non-ideal interaction between oil species or water-oil species. There is a paucity of empirical data to predict such non-ideal behavior.

The inclusion of oil species vaporization into SFPM somewhat modifies the logic structure of the original code. Figure 1 shows a brief schematic of the modified information flow in the INTCMP subroutine. Dotted lines refer to the equilibrium flash additions. At present, tests of this altered program flow structure are being debugged and tested. Successful operation in this configuration will complete the first phase of updates to SFPM to account for steam distillation effects. Subsequently, the compositional corrections mentioned above will be made regarding the necessity for their inclusion into the code. After this is done, sensitivity tests will be performed.

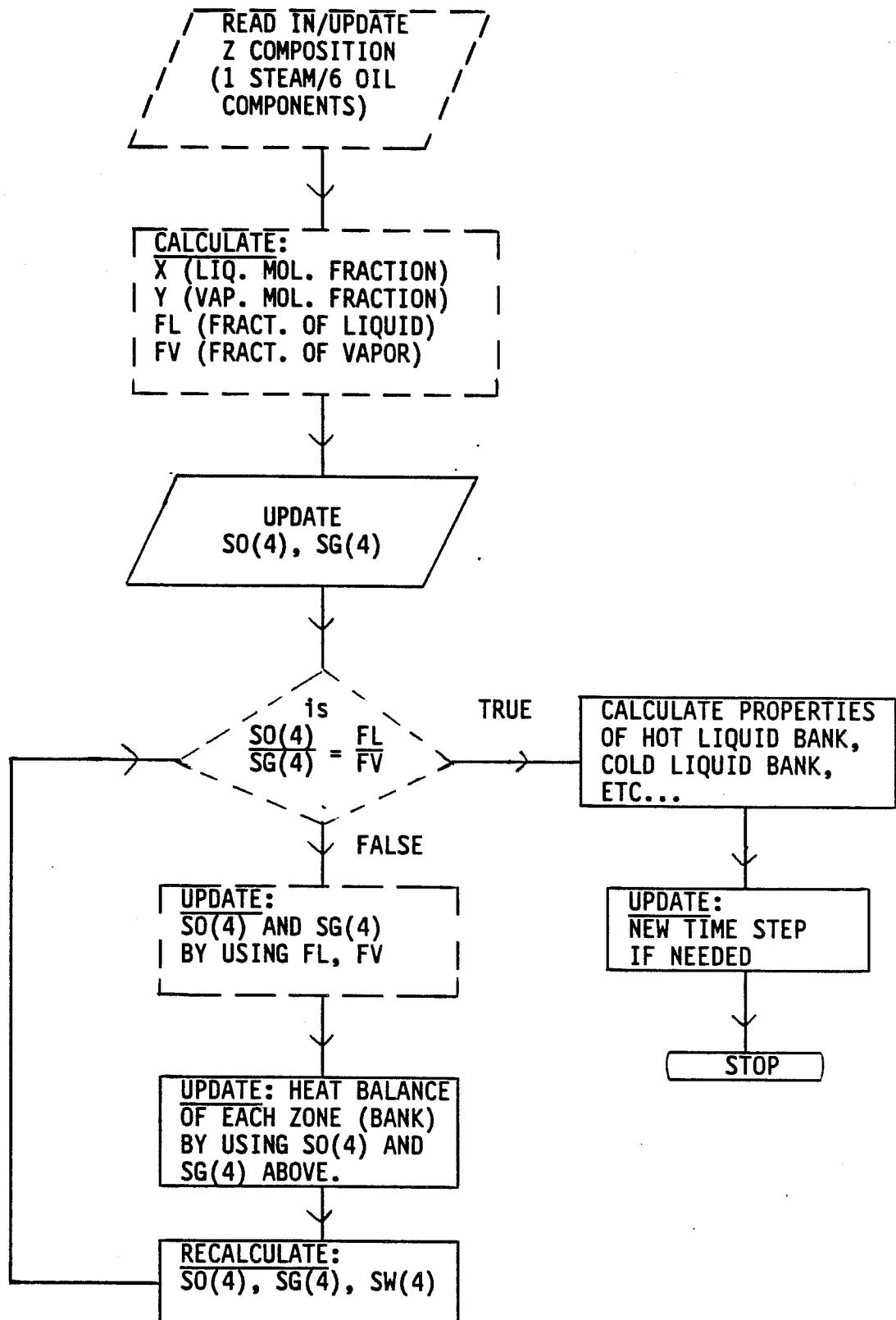


FIGURE 1 - Flow chart of logic alterations to DOE Steamflood Predictive Model (SFPM) to include equilibrium flash calculations for light oil/steam systems. Modifications are shown as dotted lines.

## II. Status of Modifications to the DOE CO<sub>2</sub> (Miscible) Flood Predictive Model (MFPM)

MFPM is a gas miscible flood predictive model based on fractional flow theory and a two phase liquid/liquid equilibrium flash calculation. These sets of equations are solved by a non-linear method of characteristics under the premise of coherent wave theory. The general equations take the form,

$$\frac{\partial C_i}{\partial t_D} + \frac{\partial F_i}{\partial X_D} = 0 \quad i = 1, 2, \dots, N \text{ species} \quad (\text{II.1})$$

$$C_i = \sum_j C_{ij} S_j \quad j = 1, 2, \dots, L \text{ phases} \quad (\text{II.2})$$

$$F_i = \sum_j C_{ij} f_j, \quad (\text{II.3})$$

where  $C_{ij}$  = concentration of species  $i$  in phase  $j$ .

$S_j$  = saturation of phase  $j$ .

In a reservoir with no slope or inclination (dip)

$$f_j = \frac{\lambda_j}{\sum_j \lambda_j}. \quad (\text{II.4})$$

In the present model, this is assumed to be the case. Inclusion of a dip angle  $\theta$  will modify the fractional flow treatment as follows:

$$f_j = \frac{\frac{1+g \sin \theta}{\Delta P} \rho_i)^{\lambda_i}}{\sum_j \lambda_j + \frac{g \sin \theta}{\Delta P} \sum_j \rho_j^{\lambda_j}} \quad (\text{II.5})$$

Modifications discussed here include adopting the formulation with dip angle. Additional definitions used here are,

$$t_D = \int_0^t \frac{q_I(t') dt'}{V_p} \quad (\text{II.6})$$

$V_p$  = total pore volume

$x_p$  =  $x/L$

L - reservoir "length" or "radius"

$q_I(t)$  = total volumetric fluid injection rate.

In MFPM,  $\text{CO}_2$  is assumed completely miscible in both an aqueous phase and an oleic (oil) phase. Therefore, at each point on a locus of compositions  $C_i(x,t)$  through the reservoir (in this case 1-dimensional) local thermodynamic phase equilibrium is guaranteed between aqueous and oleic phases by the summation,

$$\sum_{i=1}^3 C_{i2} - \sum_{i=1}^3 C_{i1} = \sum_{i=1}^3 \frac{C_i(1-K_i)}{1+S_2(K_i-1)} = 0 \quad (\text{II.7})$$

and

$$C_{i1} = \frac{C_i}{1+S_2(K_i-1)} \quad (\text{II.8})$$

with

$$C_{i2} = C_{i1} K_i \quad . \quad (\text{II.9})$$

To include a third (immiscible) gas phase, with saturation  $S_3$ , equations (II.2) and (II.3) must be modified. As a first approximation, to prevent having to perform a complete three phase equilibrium flash calculation, the physical problem will be presumed to behave as if essentially no oil or water vaporize into the gas phase. This is not an unreasonable assumption at high pressures and moderate temperatures, especially in heavy oil systems. The alternative of solving the complete three phase system would require a complex algorithm and the associated computer program would be larger than the parent program MFPM. This is beyond the scope of the present project. With these assumptions regarding non-volatility, equations (II.2) and (II.3) become

$$C_i = C_{i1} S_1 + C_{i2} S_2 + S_3 \quad i = 3 \quad (\text{II.10})$$

$$F_i = C_{i1} f_1 + C_{i2} f_2 + f_3$$

$$C_i = C_{i1} S_1 + C_{i2} S_2 \quad i = 1 \text{ and } 2 \quad (\text{II.11})$$

$$F_i = C_{i1} f_1 + C_{i2} f_2$$

Equations (II.10) and (II.11) reflect the fact that, in this case,

$$C_{3,3} = 1 \text{ and } C_{1,3} = C_{2,3} = 0.$$

For an immiscible gas flood, equations (II.10), (II.11) together with equations (II.1) - (II.5) can be solved in a manner identical to the miscible algorithm with the exception that the phase equilibration calculations are performed on a two phase normalized basis. In this manner and according to the above assumptions, the total composition paths in solution space (as determined from the non-linear method of characteristics) are solved from initial reservoir conditions to match with the set injection well conditions. During this process, the relative quantities of gas and liquid (total of oleic plus aqueous) phases are determined via fractional flow considerations, and the split of aqueous versus oleic phases is determined by the normalized two phase flash calculation. A plot of  $F_i$  versus  $C_i$  reveals the nature of the solution process and demonstrates the existence of two distinct compositional paths, which together, represent the solution for all composition values between initial and injection conditions. Figure 2 shows an example solution for  $F_3$  versus  $C_3$  ( $F_3F$  - "fast path",  $F_3S$  - "slow path") for a typical immiscible flood project with the characteristics listed in Tables 1 and 2. Also, shown here are the simulation results for the miscible model (Table 1) and the immiscible run (Table 2).

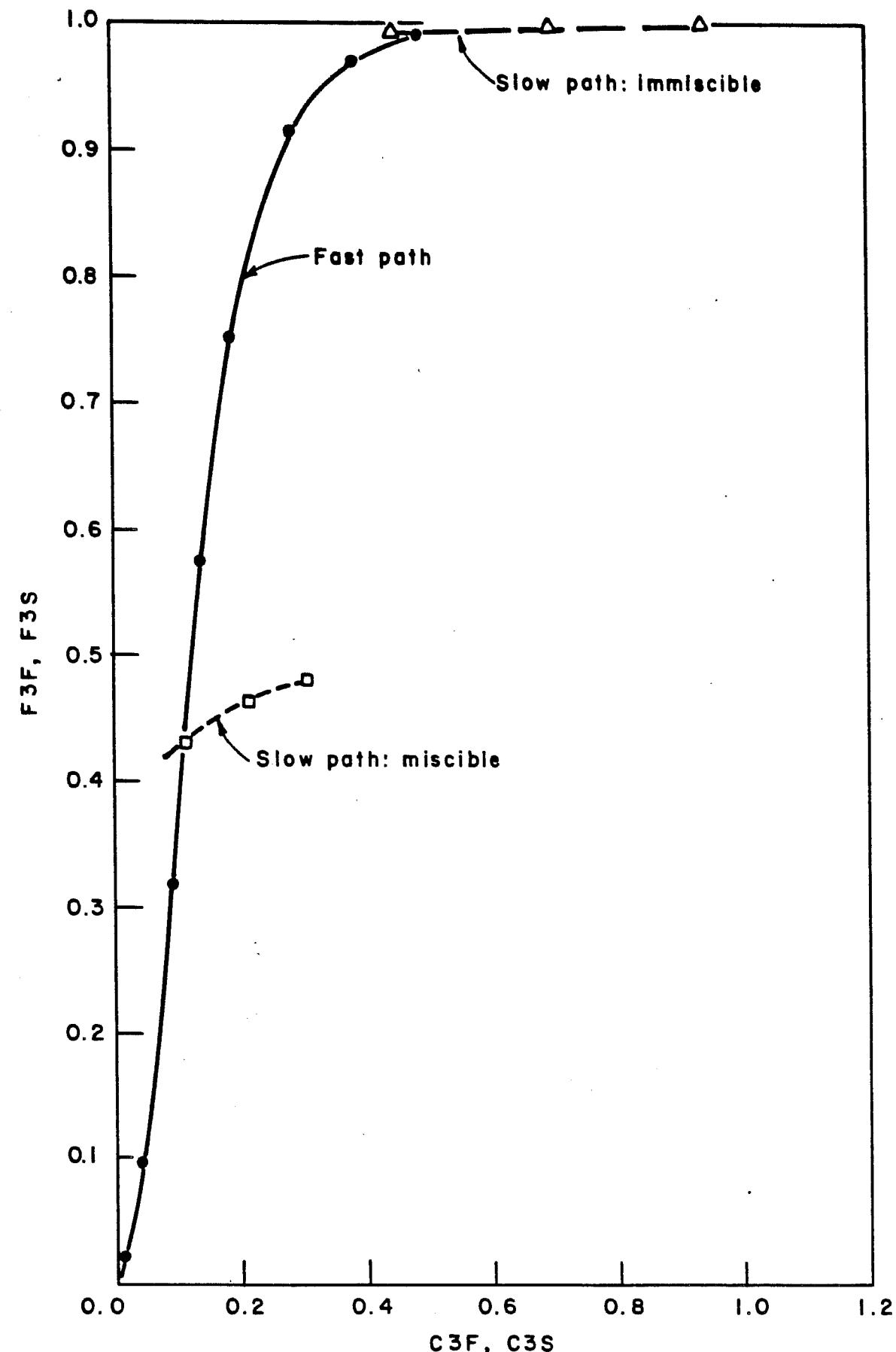


FIGURE 2: Compositional paths for total flux of  $\text{CO}_2$ . Plots show solutions for the same  $\text{CO}_2$  flood calculated by the miscible and immiscible models.

"Fast path" values correspond to the solution beginning at initial reservoir conditions, and "slow path" values continue from the "fast-slow" intersection to finish at reservoir well injection conditions. As can be seen, there is a large difference between predictions using the miscible model versus the immiscible model. This difference occurs in the portion of the solution where free gas is present; which in this case is only during the "slow path" portion of the solution. The high gas mobility is partly responsible for the higher CO<sub>2</sub> flux. An additional reason for the large difference between "slow path" values for the two examples is in the method and assumptions used to determine the well injection conditions. Currently, in the immiscible model, it is assumed that oil will reach its residual saturation in the presence of free gas at the injection well. This results in high gas saturations and mobilities throughout the slow path. A more realistic procedure is to determine injection gas and water saturations by choosing those saturations which match injection rates to equivalent mobilities. This is now being implemented.

TABLE 1

Run Conditions and Output for Miscible CO<sub>2</sub> Simulation of  
the Talco Field Immiscible Project

INPUT DECK ECHO

```

1 TEST CASE - TALCO FIELD CO2 IMMISCIBLE FLCCD PROJECT
2 1,4,1,0,0,C
3 4E4,147,0,25,200,18.5,388,3785
4 0.1,19000,1.1,200,1.0,3.79,23.0,0.7
5 0.02,C,5,0,0.01,200,1.0,2.0,4.0
6 1.0,25,0,0,0.017,0.7,0.0,0.7,1
7 1.,1.,0.9,C,5,C,0.05,C,0.30

```

\*\*\*\*\*  
\* NPC - BETC \*  
\* CO2/MISCIBLE FLOOD PREDICTIVE MCDEL \*  
\* (CC2PM - RELEASE 3.1.5) \*  
\*\*\*\*\*

TEST CASE - TALCC FIELD CO2 IMMISCIBLE FLOOD PROJECT  
OCO2 VISCOSITY TABLE, CP

TEMP	100.0	150.0	200.0	250.0	300.0
PRESS					
0.0	C.0100	C.0100	C.0100	C.0100	C.0100
1000.0	C.0270	C.0170	C.0170	C.0170	C.0170
2000.0	C.0650	C.0350	C.0270	C.0250	C.0230
3000.0	C.0820	C.0560	C.0410	C.0340	C.0270
5000.0	C.1020	C.0790	C.0640	C.0530	C.0460
7000.0	C.1150	C.0940	C.0780	C.0660	C.0590

OCO2 DENSITY TABLE, G/CC

TEMP	100.0	150.0	200.0	250.0	300.0
PRESS					
1000.0	0.2030	0.1500	0.1230	0.1000	0.0970
1500.0	0.7040	0.2750	0.2120	0.1750	0.1550
2000.0	0.8010	0.5000	0.3170	0.2500	0.2170
3000.0	0.8680	0.7200	0.5170	0.4050	0.3460
4000.0	0.9070	0.7750	0.6560	0.5500	0.4600
5000.0	0.9360	0.8300	0.7390	0.6350	0.5520
7000.0	0.9940	0.9100	0.8310	0.7400	0.6820

OCO2 SOLUBILITY IN WATER, SCF/BBL

TEMP	70.0	100.0	130.0	160.0	190.0
PRESS					
0.0	0.0	0.0	0.0	0.0	0.0
1000.0	185.0	150.0	120.0	100.0	85.0
1500.0	195.0	170.0	150.0	130.0	110.0
2000.0	205.0	175.0	155.0	140.0	130.0
3000.0	210.0	185.0	170.0	160.0	155.0
7000.0	245.0	220.0	205.0	200.0	200.0

TABLE 1 (Continued)

\*\*\*\*\*  
 \* NFC - BETC  
 \* CO2/MISCIBLE FLOOD PREDICTIVE MODEL  
 \* (CC2PM - RELEASE 3.1.5)  
 \*\*\*\*\*

TEST CASE - TALCO FIELD CO2 IMMISCIBLE FLOOD PROJECT

CASE CONTROLS

RESERVOIR CALC METHOD .....	1	IRES
INTERMEDIATE OUTPUT .....	4	IOUT
ACCOUNT FCR CO2/WATER SOLUBILITY .....	1	ISOL
NUMBER OF LAYERS (NO CROSSFLOW) .....	1	LAYERS
FORMATION PROPERTIES		
FORMATION PRESSURE .....	484.0	PSIA
FORMATION TEMPERATURE .....	147.0	DEG.F
POROSITY .....	0.2500	FRACTION
NET THICKNESS (PAY) .....	200.0	FEET
PATTERN AREA .....	18.50	ACRES
PERMEABILITY .....	388.0	MD
DEPTH .....	3785.0	FT
VERT/FORIZ PERMEABILITY RATIO .....	0.1000	KV/KH
RESERVOIR WATER SALINITY .....	190000.	PPM
INITIAL CONDITIONS		
INITIAL OIL FRACTIONAL FLOW .....	0.0200	FRACTN
PATH CONCENTRATION INCREMENT .....	0.010000	FRACTN
RESERVOIR INJECTION RATE .....	200.0	BBL/DAY
INJECTED WAG RATIO .....	1.000	WATR/CO2
HCPV OF CO2/WATER INJECTED (SLUG) .....	2.0000	HCPV
MAX HCPV INJECTED (SLUG+CHASE) .....	4.0000	HCPV
INITIAL AQUEOUS PHASE SATN .....	0.5606	FRACTN
INITIAL OLEIC PHASE SATN .....	0.4394	FRACTN
WATER VISCOSITY .....	1.0271	CP
OIL VISCOSITY .....	25.0000	CP
CO2 VISCOSITY .....	0.0170	CP
WATER VOLUME FACTOR .....	1.0000	RB/STE
OIL VOLUME FACTOR .....	1.1000	RB/STE
CO2 COMPRESSIBILITY FACTOR .....	0.8784	1/PSI
CO2 VOLUME FACTOR .....	3.7900	RB/MCF
OIL GRAVITY .....	23.00	DEG.API
WATER DENSITY .....	1.1167	G/CC
CO2 DENSITY .....	0.1532	G/CC
CO2 DENSITY .....	9.6	LB/CU.FT
CO2 SOLUBILITY IN WATER .....	25.1	SCF/BBL
OIL SOLUTION GAS CONTENT .....	200.0	SCF/BBL
INTERNAL CYKSTRA-PARSONS CCEFF .....	0.7000	VDP

TABLE 1 (Continued)

RELATIVE PERM CURVES

OIL RELATIVE PERM CURVATURE	.....	1.00
WATER RELATIVE PERM CURVATURE	.....	1.00
OIL RELATIVE PERM END-POINT	.....	0.9000
WATER RELATIVE PERM END-PCINT	.....	0.5000
IRREDLICBLE WATER SATURATION	.....	0.0500
RESIDLAL CIL SATN AFTER WATER	.....	0.300

RELATIVE PERMEABILITY TABLE

WATER SATLRATN	OIL KRC	WATER KRW	FRACTION WATER	DERIV DFw/DSw
0.0500	0.9000	0.0000	0.0000	0.000
0.0825	0.8550	0.0250	0.4158	0.867
0.1150	0.8100	0.0500	0.6004	1.101
0.1475	0.7650	0.0750	0.7047	1.511
0.1800	0.7200	0.1000	0.7714	1.694
0.2125	0.6750	0.1250	0.8188	1.919
0.2450	0.6300	0.1500	0.8555	1.718
0.2775	0.5850	0.1750	0.8790	1.576
0.3100	0.5400	0.2000	0.9030	1.473
0.3425	0.4950	0.2250	0.9171	1.955
0.3750	0.4500	0.2500	0.9311	1.334
0.4075	0.4050	0.2750	0.9442	1.687
0.4400	0.3600	0.3000	0.9530	1.449
0.4725	0.3150	0.3250	0.9617	1.218
0.5050	0.2700	0.3500	0.9699	1.193
0.5375	0.2250	0.3750	0.9755	1.171
0.5700	0.1800	0.4000	0.9818	1.153
0.6025	0.1350	0.4250	0.9871	1.125
0.6350	0.0900	0.4500	0.9919	0.000
0.6675	0.0450	0.4750	0.9961	
0.7000	0.0000	0.5000	1.0000	

TABLE 1 (Continued)

TABLE 2

Run Conditions and Output for Immiscible CO<sub>2</sub> Simulation of  
the Talco Field Immiscible Project

INPUT DECK ECHO

```

1 TEST CASE - TALCO FIELD CO2 IMMISCIBLE FLCCD PROJECT
2 1,4,1,C,0,0
3 484,147,0,25,200,18.5,388,3785
4 0,1,190000,1,1,200,1,0,3,79,23.0,0,7
5 0,02,C,5,0,0,01,200,1,0,2,0,4,0
6 1,0,25,0,0,017,0,7,0,0,0,7,1
7 1,1,C,9,C,5,C,0,05,C,0,30
8 0,98C,
9 1,0,0,0,916,0,061
10 0,5,0,0,1,0

```

\*\*\*\*\*  
\* NPC - BETC \*  
\* CO2/MISCIBLE FLOOD PREDICTIVE MODEL \*  
\* (CO2PM - RELEASE 3.1.5) \*  
\*\*\*\*\*

TEST CASE - TALCC FIELD CO2 IMMISCIBLE FLOOD PRJECT  
CO2 VISCOSITY TABLE, CP

TEMP	100.0	150.0	200.0	250.0	300.0
PRESS	0.0100	0.0100	0.0100	0.0100	0.0100
0.0	0.0100	0.0100	0.0100	0.0100	0.0100
1000.0	0.0270	0.0170	0.0170	0.0170	0.0170
2000.0	0.0650	0.0350	0.0270	0.0250	0.0230
3000.0	0.0820	0.0560	0.0410	0.0340	0.0270
5000.0	0.1020	0.0790	0.0640	0.0530	0.0460
7000.0	0.1150	0.0940	0.0780	0.0660	0.0590

TEMP	100.0	150.0	200.0	250.0	300.0
PRESS	0.2030	0.1500	0.1230	0.1000	0.0970
1000.0	0.7040	0.2750	0.2120	0.1750	0.1550
2000.0	0.8010	0.5000	0.3170	0.2500	0.2170
3000.0	0.8680	0.7000	0.5170	0.4550	0.3460
4000.0	0.9070	0.7750	0.6560	0.5500	0.4600
5000.0	0.9360	0.8300	0.7390	0.6350	0.5520
7000.0	0.9940	0.9100	0.8310	0.7400	0.6820

TEMP	70.0	100.0	130.0	160.0	190.0
PRESS	0.0	0.0	0.0	0.0	0.0
0.0	0.0	0.0	0.0	0.0	0.0
1000.0	185.0	150.0	120.0	100.0	85.0
1500.0	195.0	170.0	150.0	130.0	110.0
2000.0	205.0	175.0	155.0	140.0	130.0
3000.0	210.0	185.0	170.0	160.0	155.0
7000.0	245.0	220.0	205.0	200.0	200.0

**TABLE 2 (Continued)**

\*\*\*\*\*  
 \* NFC - BETC \*  
 \* CO2/MISCIBLE FLOOD PREDICTIVE MODEL \*  
 \* (CO2PM - RELEASE 3.1.5) \*  
 \*\*\*\*\*

TEST CASE - TALCO FIELD CO2 IMMISCIBLE FLOOD PROJECT

CASE CCNTRCLS

RESERVOIR CALC METHOD .....	1	IRES
INTERMEDIATE OUTPUT .....	4	IOUT
ACCOUNT FOR CO2/WATER SOLUBILITY .....	1	ISOL
NUMBER OF LAYERS (NO CROSSFLOW) .....	1	LAYERS
FORMATION PROPERTIES		
FORMATION PRESSURE .....	484.0	PSIA
FORMATION TEMPERATURE .....	147.0	CEG.F
PERMEABILITY .....	0.2500	FRACTION
NET THICKNESS (PAY) .....	200.	FEET
PATTERN AREA .....	18.50	ACRES
PERMEABILITY .....	388.0	ME
DEPTH .....	3785.0	FT
VERT/HCRIZ PERMEABILITY RATIO .....	0.1000	KV/KH
RESERVOIR WATER SALINITY .....	190000.	PPM
INITIAL CONDITIONS		
INITIAL OIL FRACTIONAL FLOW .....	0.0200	FRACTN
PATH CONCENTRATION INCREMENT .....	0.010000	FRACTN
RESERVOIR INJECTION RATE .....	200.0	BBL/DAY
INJECTED WAG RATIO .....	1.000	WATR/CO2
HCPV CF CO2/WATER INJECTED (SLUG) .....	2.0000	HCPV
MAX HCPV INJECTED (SLUG+CHASE) .....	4.0000	HCPV
INITIAL AQUEOUS PHASE SATN .....	0.5606	FRACTN
INITIAL CLEIC PHASE SATN .....	0.4394	FRACTN
WATER VISCOSITY .....	1.0271	CP
OIL VISCOSITY .....	25.0000	CP
CO2 VISCOSITY .....	0.0170	CP
WATER VOLUME FACTOR .....	1.0000	RE/STB
OIL VOLUME FACTOR .....	1.1000	RE/STB
CO2 COMPRESSIBILITY FACTOR .....	0.8784	1/PSI
CO2 VOLUME FACTOR .....	3.7900	RE/MCF
OIL GRAVITY .....	23.00	DEG.API
WATER DENSITY .....	1.1167	G/CC
CO2 DENSITY .....	0.1532	G/CC
CO2 DENSITY .....	9.6	LB/CU.FT
CO2 SOLUBILITY IN WATER .....	25.1	SCF/BBL
OIL SCLUTION GAS CCNTENT .....	200.0	SCF/EBL
INTERNAL DYKSTRA-PARSONS COEFF .....	0.7000	VDP

TABLE 2 (Continued)

RELATIVE PERM CURVES

OIL RELATIVE PERM CURVATURE .....	1.00
WATER RELATIVE PERM CURVATURE .....	1.00
OIL RELATIVE PERM END-POINT .....	0.900
WATER RELATIVE PERM END-PCINT .....	0.500
IRREDLICBLE WATER SATURATION .....	0.050
RESIDLAL OIL SATN AFTER WATER .....	0.300

RELATIVE PERMEABILITY TABLE

WATER SATLRATN	OIL KRO	WATER KRW	FRACTION WATER	DERIV DFW/DSW
0.0500	0.0001	0.0000	0.1106	0.000
0.0825	0.0000	0.0250	1.0000	0.000
0.1150	0.0000	0.0500	1.0000	0.000
0.1475	0.0000	0.0750	1.0000	0.000
0.1800	0.0000	0.1000	1.0000	0.000
0.2125	0.0000	0.1250	1.0000	0.000
0.2450	0.0000	0.1500	1.0000	0.000
0.2775	0.0000	0.1750	1.0000	0.000
0.3100	0.0000	0.2000	1.0000	0.000
0.3425	0.0000	0.2250	1.0000	0.000
0.3750	0.0000	0.2500	1.0000	0.000
0.4075	0.0000	0.2750	1.0000	0.000
0.4400	0.0000	0.3000	1.0000	0.000
0.4725	0.0000	0.3250	1.0000	0.000
0.5050	0.0000	0.3500	1.0000	0.000
0.5375	0.0000	0.3750	1.0000	0.000
0.5700	0.0000	0.4000	1.0000	0.000
0.6025	0.0000	0.4250	1.0000	0.000
0.6350	0.0000	0.4500	1.0000	0.000
0.6675	0.0000	0.4750	1.0000	0.000
0.7000	0.0000	0.5000	1.0000	0.000

TABLE 2 (Continued)